Exhibit

AS-4

Reference Case, we first developed a forecast of total rates under Reference Case assumptions. This forecast leveraged our detailed five-year financial forecast and a specific approach to identify costs through the end of the planning period (2034) using the CAGR of generation and fuel costs from the Strategist model.[2] Next, we analyzed the annual cost differences by category (i.e. fuel, purchased power, capital expenditures, operating and maintenance costs, taxes, depreciation, etc.) from the Strategist model results for the Reference Case and the Preferred Plan to determine the aggregate system cost impacts and jurisdictional and rate class breakouts.

To determine the overall impact to Minnesota customers and individual customer classes in Minnesota, we converted the differential in annual expenses and capital spend of the Preferred Plan compared to the Reference Case into a differential revenue requirement forecast. We then jurisdictionalized the differential revenue requirements and applied class allocation principles to calculate impacts on individual Minnesota customer classes. We provide various rate impact analyses and discuss the methodologies below.

II. ESTIMATED RATE IMPACTS AND METHODOLOGY

The primary Strategist model captures only the generation-related portion of the business, or around 50 percent of the total revenue requirements. Developing a total rate forecast beyond 2023 when detailed Company financial models are not available is dependant on making assumptions for capital expenditures and O&M costs for all areas of the business, including generation (both new and existing), transmission, distribution and corporate support services. Many of these assumptions are speculative, and the resulting total rate forecast would be similarly speculative.

A. Methodology

To calculate the rate impacts of the Preferred Plan, we started with the 2018 budget forecast of total revenue requirements for the 2019-2023 period.[3] To estimate customer impacts for the immediate five-year period, we estimated revenue requirements similar to a Jurisdictional Cost of Service (JCOSS) for each year, and then performed an estimated Class Cost of Service (CCOSS) analysis – both of which required us to make a number of assumptions.

[2] The Strategist model for the Reference Case is the same model used for the Strategist aspect of our Baseload Study, Scenario 1 Reference Case, with the exception that the first Demand Response (DR) bundle was added to the plan, as was also added to the Preferred Plan.
[3] Developed in July 2018 and updated in November 2018.

To determine the JCOSS, we had to make a number of assumptions, including the following:

- Full recovery of the Company's internal five-year forecasts of capital, O&M, and sales,[4]
- Return on Equity (ROE) of 9.20 percent,[5]
- A forecast of debt and equity ratios and debt rates appropriate for the five-year modeling term,
- Estimated historical regulatory adjustments made in rate cases.

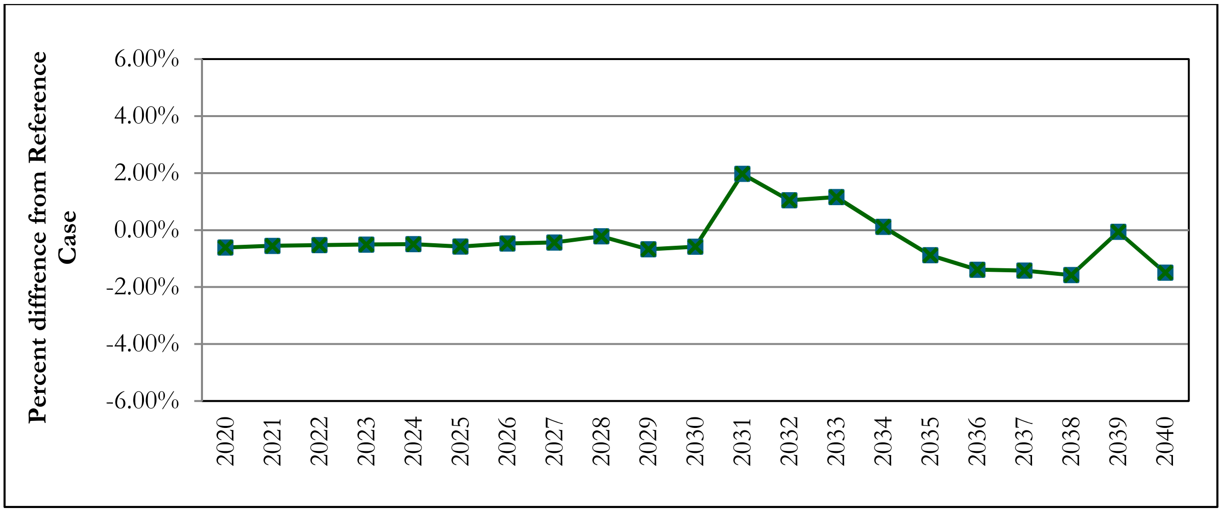
To calculate longer-term rate impacts of the Preferred Plan, we used a combination of the Company's 5-year financial forecast and the Strategist model to project total system revenue requirements for extended periods. For the period beyond 2023, we escalated the capital and O&M costs in the last year of the 5-yr model by the CAGR of the Reference Case as modeled by Strategist.[6] This approach avoids speculation on areas of the business not related to resource planning and modeling, while still using the detailed generation-related information from the Strategist model to create a "business as usual" long term rate projection. Finally, we calculated the annual difference between the Preferred Plan and the Reference Case to estimate the total rate impact of our Preferred Plan.

B. Estimated Overall Rate Impacts

Figure 6-3 below illustrates the State of Minnesota estimated rate impacts of the Preferred Plan compared to the Reference Case over the long-term.

[4] Data as of November 2018.
[5] The Company acknowledges the recent decision in the TCR docket requiring a 9.06% calculation to be used in future filings and will implement that practice once the order is received.
[6] The Reference Case is Resource Plan Scenario 1; see Appendix F2 for additional details.

Figure 6-3: Annual Percent Change in Revenue Requirements (2020-2040) Preferred Plan above Reference Case – State of Minnesota



The modeling includes accelerated depreciation costs associated with the early retirements of Sherco 3 and King. However, consistent with the Commission's actions in the approval of the early shutdown of the Benson biomass plant (Docket No. E002/M-17-530), a regulatory asset is another tool that could be used to accompany these early retirements. The use of a regulatory asset for the remaining costs of these plants, including a cost of capital return on those assets, would be an appropriate alternative to accelerating the depreciation because it would keep the Company whole over the remainder of the plants' remaining lives. This would also serve to smooth the projected rate impacts over the planning period.

C. Key Drivers

The major inflection points in the delta of revenue requirements (and rates) is driven entirely by the differences in the set of resources that comprise each the Preferred Plan and Reference Case; these points coincide with key differences in baseload plant retirement dates between the two cases and the timing of replacement resources. The reduction in revenue requirements associated with the early coal unit retirements helps to offset a portion of the ongoing nuclear revenue requirements in the Preferred Plan in the early 2030s, as discussed in more detail below:

- *Extension of Monticello.* In 2028, costs associated with the 10-year license extension begin to ramp up in the Preferred Plan, and capital revenue requirements and O&M costs continue through 2040. In contrast, the Reference Case does not have ongoing capital and O&M costs for Monticello beyond 2030 as it is retired in that case; this results in an approximate $295 million difference between the two cases in fixed costs for Monticello, beginning in 2031.

- *Retirement of Coal Units.* The Reference Case contains ongoing capital and O&M costs for King and Sherco Unit 3, whereas in the Preferred Plan the costs for King terminate in 2029 and Sherco Unit 3 in 2031 due to early retirement. This results in savings of approximately $45 million in fixed costs in 2029, increasing to $110 million in 2031.

- *Load Supporting Resources.* The Preferred Plan has some load-supporting, dispatchable resources added in the early 2030's associated with the Reliability Requirements Proxy discussed in the Baseload Study in this Resource Plan. With the early retirement of King and Sherco Unit 3, the Preferred Plan has a load supporting, dispatchable resource deficiency of approximately 400 MW in that time frame. The Preferred Plan extension of Monticello helps to offset some of this capacity deficiency. The net cost of the load supporting, dispatchable resources in those years ranges from approximately $35 million to $70 million.

The rate increase seen in 2031-2033 reverses in 2034 and the Preferred Plan remains an annual savings producer thereafter. The cost savings from the Preferred Plan are due to the extension of Monticello, which maintains the NSP system 80 percent carbon reduction after Prairie Island retires, without the need to add significant renewables. In the Reference Case, the model adds 2,250 MW of wind in 2034-35 to maintain the 80 percent carbon reduction level, which adds significant costs.

D. These Estimates are not Directly Comparable to Rate Impact Analysis in a Rate Case

We caution that this information should not be interpreted as directly comparable to the customer rate impact information we would provide as part of a rate case filing for reasons including the following:

- The internal forecast for 2019-2023 is not prepared at the level of detail necessary to support a rate case,

- While the forecast includes typical regulatory adjustments, we have not attempted to remove one-time effects or other one-time adjustments that are not specifically known at this time,

- We have made no assumptions of a rate case filing schedule over this period; the forecast provided assumes full recovery of annual deficiencies, suggesting a full rate case annually, and

- All factors of the Cost of Capital, including debt rates, return on equity, and debt-equity ratios, are subject to change over the period.

III. ESTIMATED RATE IMPACTS BY CLASS PER YEAR

After determining the incremental revenue requirement impacts from the Preferred Plan and Reference Case for the Minnesota jurisdiction, we determined *class* revenue requirement impacts. We provide the estimated impacts below, then discuss the methodology and calculations that we used. The incremental revenue requirement impact of the Preferred Plan versus the Reference Case is shown in column 3 of Table 6-1 below. Column 4 of the below Table also shows the incremental impact of the Preferred Plan as a percent of the total State of Minnesota revenue requirement.

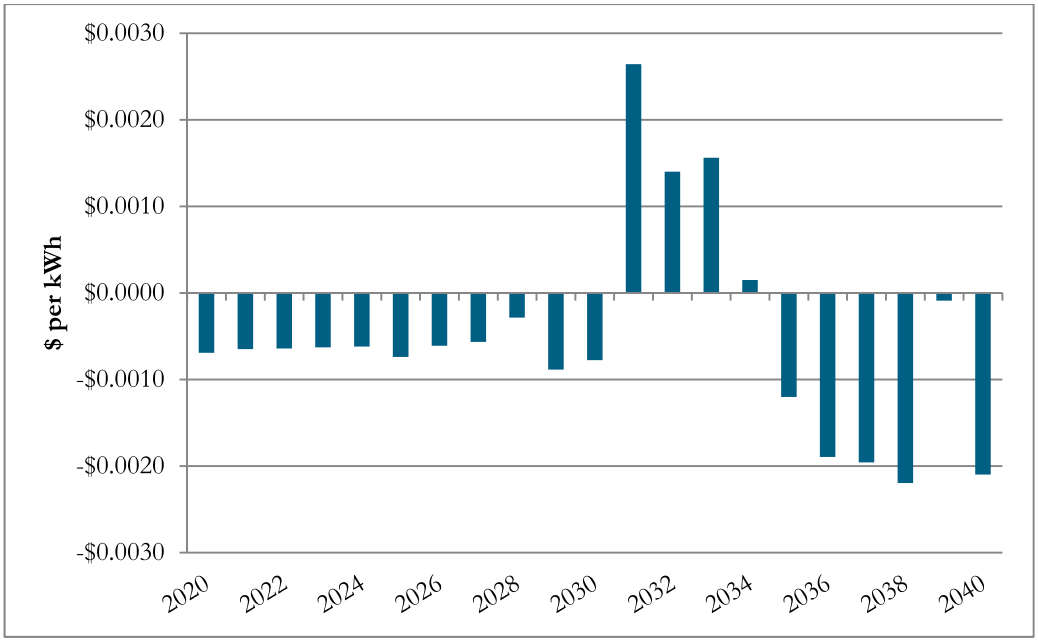
We calculated rate impacts in $ per kWh by dividing each class's revenue requirement in each year by the forecasted sales in each year.

Table 6-1: Estimated Incremental Impact of Preferred Plan
State of Minnesota – All Customers

1	2	3	4
Year	**State of MN Total Revenue Req ($000)**	**Incremental Impact of Preferred Resource Plan** ($000)	**Incremental Impact (%)**
2019	$3,241,019		
2020	$3,309,662	-$20,307	-0.61%
2021	$3,407,431	-$18,905	-0.55%
2022	$3,531,080	-$18,646	-0.53%
2023	$3,567,006	-$18,163	-0.51%
2024	$3,614,422	-$17,880	-0.49%
2025	$3,662,468	-$21,259	-0.58%
2026	$3,711,153	-$17,597	-0.47%
2027	$3,760,484	-$16,389	-0.44%
2028	$3,810,472	-$8,389	-0.22%
2029	$3,861,124	-$26,054	-0.67%
2030	$3,912,450	-$22,932	-0.59%
2031	$3,964,457	$78,174	1.97%
2032	$4,017,157	$41,948	1.04%
2033	$4,070,556	$47,089	1.16%
2034	$4,124,665	$4,568	0.11%
2035	$4,179,494	-$36,862	-0.88%
2036	$4,235,052	-$58,945	-1.39%
2037	$4,291,348	-$61,023	-1.42%
2038	$4,348,392	-$68,746	-1.58%
2039	$4,406,195	-$2,809	-0.06%
2040	$4,464,766	-$66,728	-1.49%

We visually portray this information in Figure 6-4 below.

Figure 6-4: Incremental Rate Impact of Preferred Plan
State of Minnesota – All Customers



A. Methodology and Calculations

We determine class revenue requirement impacts by allocating incremental costs to rate classes for each year in the planning period (2020-2034). After costs are allocated, we then calculate revenue requirement impacts for each customer class.

We apply ratemaking treatments to expense items that are impacted by the Resource Plan, as follows:

- Fuel Costs
- Purchased Energy
- Production O&M Expenses
- Property Taxes
- Deferred Income Taxes
- Tax Depreciation and Removal Expense,
- Decommissioning Accruals
- Plant In Service and Associated Depreciation, Construction Work in Progress (CWIP), and Accumulated Deferred Income Taxes

- Bulk Transmission Costs

We discuss our treatment of these expense items for purposes of this rate impact analysis below.

B. Fuel Costs and Purchased Energy

Fuel and purchased energy costs are allocated to classes using the E8760 energy allocator approved in our most recent Minnesota rate case, as provided below:[7]

Table 6-2: E8760 Energy Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	29.27%	3.04%	67.24%	0.44%

The E8760 allocator is calculated by taking the forecast hourly load for each of the 8,760 hours of the test year for each customer class, then weighting the hourly load by the forecasted hourly marginal energy cost in each respective hour.

C. Production Expense, Property Taxes, Deferred Income Taxes, Tax Depreciation and Removal Expense and Decommissioning Accrual

These expense items are split into energy-related and capacity/demand-related components using the Company's plant stratification analysis approved in our most recent Minnesota rate case.[8] We provide the approved plant stratification analysis that we applied to production O&M expenses for each plant type below:

[7] See Docket No. E002/GR-15-826, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, (June 12, 2017).
[8] *Id.*

Table 6-3: Stratification Analysis by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity/Demand Percentage	Energy Percentage
Combustion Turbine	$825	$825 / $825	100.0%	0.0%
Fossil	$2,089	$825 / $2,089	39.5%	60.5%
Nuclear	$4,286	$825 / $4,286	19.3%	80.7%
Combined Cycle	$1,079	$825 / $1,079	76.5%	23.5%
Wind	$15,847	$825 / $15,847	5.2%	94.8%
Solar	$8,182	$825 / $8,182	10.1%	89.9%

The plant stratification approach begins by comparing the replacement cost of each type of generation plant (fossil, combined cycle, nuclear, etc.) to the replacement cost of a CT. CT are 100 percent capacity/demand-related since they are the generation source with the lowest capital cost and the highest operating cost. For each generation type, the percent of total generation costs that exceeds the cost of a CT peaking plant are classified as being energy-related. These costs are in excess of the capacity/demand-related portion, and as such, were not incurred to obtain capacity, but rather to obtain lower cost energy.

After production O&M costs originating from each type of generation plant are split into capacity-related and energy-related components based on the percentages shown in Table 6-3 above, those costs that have been classified as being energy-related are allocated to class using the E8760 energy allocator provided in *part 1* above.

The capital costs that have been classified as being capacity- or demand-related are allocated to customer class using the D10S capacity allocator approved by the Commission in our most recent rate case.[9] The D10S allocator is simply each class's load that is coincident with the NSP system peak load. We provide the approved D10S class allocator percentages below:

Table 6-4: D10S Capacity Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	36.14%	3.28%	60.59%	0.00%

[9] *Id.*

D. Generation Rate Base Costs Including Plant in Service, Depreciation, CWIP and Accumulated Deferred Income Taxes

Rate base related costs from each type of generation plant are also split into energy-related and capacity/demand-related components using the Company's plant stratification analysis approved in our most recent Minnesota rate case.[10] As was true with the expense items listed in *part 2* above, rate base costs classified as being energy-related are allocated to class using the E8760 energy allocator. Likewise, the capital costs that have been classified as being capacity or demand-related are allocated to customer class using the D10S capacity allocator.

E. Bulk Transmission Costs

As ordered by the Minnesota Commission, all rate base and expense items related to bulk transmission are classified as being capacity or demand-related and are allocated to customer class using the Commission-approved D10S capacity allocator.[11]

IV. DETERMINING CLASS RATE IMPACTS

In order to show the estimated impacts of the Preferred Plan on customer rates and bills, we provide a breakdown by customer class for the 2020-2040 period, and in more detail for the immediate five-year 2019-2023 period at the Minnesota customer class levels.

Figure 6-5 below shows the estimated incremental impacts of our Preferred Plan over the long-term by customer class.

[10] *Id.*
[11] *Id.*

Figure 6-5: Incremental Rate Impact of Preferred Plan by Customer Class – State of Minnesota

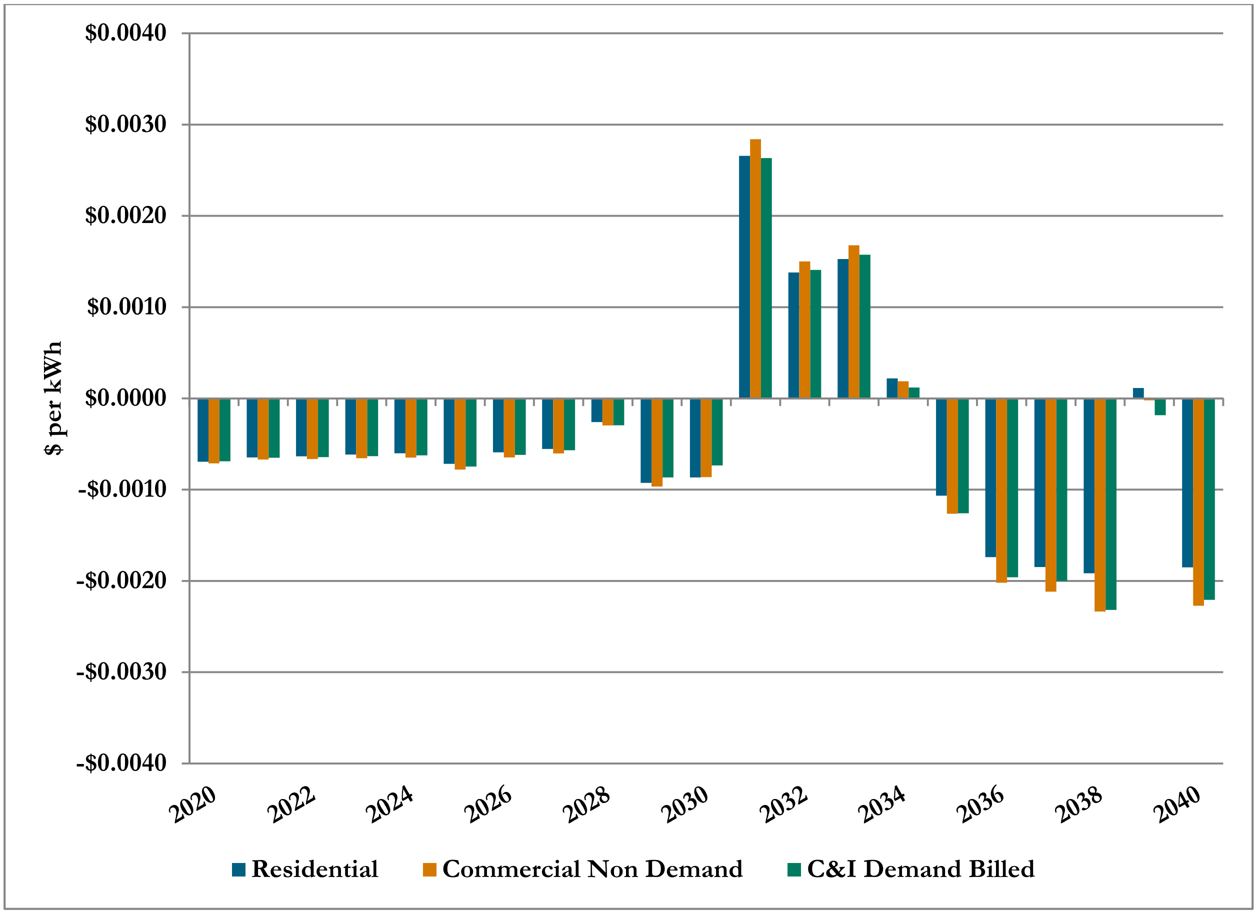


Table 6-5 below provides a more detailed view of near-term estimated rate impacts for Minnesota customer classes.

Table 6-5: Preferred Plan Estimated Rate Impacts by Class per Year

Rate Class Impacts \1	2019	2020	2021	2022	2023	2024	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)	14.488¢	14.367¢	14.506¢	14.847¢	15.377¢	15.526¢	N/A
Cumul Increase (¢/kWh)		-0.121	0.018	0.359	0.889	1.037	N/A
Cumulative Increase (%)		-0.84%	0.12%	2.48%	6.14%	7.16%	1.39%
$ Impact/Month, @ 650	($0.79)	$0.11	$2.33	$5.78	$6.74	N/A	N/A
Sm Non-Dmd (avg rate, ¢/kWh)	13.218¢	13.218¢	13.167¢	13.511¢	13.946¢	14.599¢	14.855¢
Cumul Increase (¢/kWh)		-0.052	0.293	0.727	1.380	1.636	N/A
Cumulative Increase (%)		-0.39%	2.22%	5.50%	10.44%	12.38%	2.36%
$ Impact/Month, @ 1,000	($0.52)	$2.93	$7.27	$13.80	$16.36	N/A	N/A
Demand (avg rate, ¢/kWh)	9.370¢	9.300¢	9.707¢	10.040¢	10.471¢	10.570¢	N/A
Cumul Increase (¢/kWh)		-0.070	0.336	0.669	1.100	1.199	N/A
Cumulative Increase (%)		-0.75%	3.59%	7.14%	11.74%	12.80%	2.44%
$ Impact/Month, @ 37,500	($26.30)	$126.15	$250.98	$412.56	$449.71	N/A	N/A
Street Ltg (avg rate, ¢/kWh)	25.290¢	25.027¢	24.668¢	24.917¢	25.624¢	26.079¢	N/A
Cumul Increase (¢/kWh)		-0.262	-0.622	-0.372	0.334	0.790	N/A
Cumulative Increase (%)		-1.04%	-2.46%	-1.47%	1.32%	3.12%	0.62%
$ Impact/Month, @ 60	($0.16)	($0.37)	($0.22)	$0.20	$0.47	N/A	N/A

Using the methodologies described above, the incremental costs in the last year of the period (2024) for the Preferred Plan would be expected to increase the average Residential rate by about 1.39 percent on a compounded annual basis through 2024. That is equivalent to a total increase of $6.74 per month above the current rate level.

The impact to the average Large Demand Billed rate would be an increase of about 2.44 percent on a compounded annual basis through 2023, which is equivalent to an increase of 1.199 cents per kWh above the 2019 level.

V. FACTORS IMPACTING NEAR-AND LONG-TERM RATE ESTIMATES

We note that the following factors could have an impact on the estimated rate impacts in the planning period:

Depreciation Expense for Coal Closures. The modeling and estimated rate impacts reflect accelerated depreciation associated with the early retirement of the Allen S. King and Sherco Unit 3 plants. This is consistent with the Company's current method of recovery for Sherco 1 and 2. As noted previously, however, and consistent with the Commission's actions in the approval of the early shutdown of the Benson biomass plant, a regulatory asset is another tool that could be used to accompany these early retirements. An alternative regulatory treatment such as this would impact this analysis.

Generation Ownership: Owned and Purchased Power Agreement resources will have different cost patterns, which will impact this analysis to the extent a resource addition differs in terms of ownership from what was modeled.

Taxes. This analysis is based on present tax conditions. Any tax changes will impact the modeling underlying this analysis and thus the rate impact results.

Nuclear Decommissioning Trust. There are several items regarding the NDT that may have a material impact on costs included in this resource plan.

Pending or Future Regulatory Decisions. Rate case and resource acquisition outcomes have the potential to impact rates and system needs.

Large Customer Changes. The loss or addition of a large business customer has the potential to impact both rates and system needs.